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Design, Construct, Install and Test G.O.A.L. PetroPumps in 1 Oil and 6 Gas wells

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Abstract

A 'Gas Operated Automated Lift Pump' G.O.A.L. PetroPump has been conceptually developed constructed in prototype and beta type tools, field tested and found to be applicable for use in removing fluids from "stripper wells" thereby increasing production of natural gas. Per the agreement with the Stripper Well Consortium '7' wells have been tested with the tool. Test results have shown a 1.5X to 4.0+ X increase in gas yields from wells tested. Bench scale and laboratory test of the key tool component, the automated pressure controlled valve assembly, has established the potential applicability of a prototype tool/ beta tool [field ready] in watered out stripper wells. Tool applicability is targeted to operating conditions of 50 to 600+ psi down hole pressure with brine and fluid lift capacity varying from 0.1 to 9.0+ BBL/ tool cycle. In field precursor testing of a pilot predecessor tool of larger dimensions and weight than that targeted for fabrication and deployment as part of this SWC 7 well program had shown promising results. The precursor field test of tool [s] have shown improved natural gas production 1.6 X to 2.4X, regular automatic cycling of tool [1 Trip each 1 –1.5 Day] and auto lifting of brines [0.33 – 1.5Bbl/cycle] from a brine producing natural gas stripper well. Field testing of the above referenced designed prototype tool for this phase of the project showed similar brine production [0.25 to 1 Bbl/ tool run with 1 to 2 day cycles] and frequency of tool cycles during the early period of field trials. Field trials of the prototype [smaller body and length] tool evidenced metallurgy problems in materials construction compatibility resulting in premature actuator failure and decreasing frequency of tool runs and lesser quantity of fluids production with each subsequent tool trip. Field and laboratory analysis diagnosed the problem and designed a remedy for further in field-testing. This premature failure was diagnosed as corrosion on one of the actuator components. The problem occurred as a function of miniaturizing of components to achieve a desired, "well tender friendly" smaller tool configuration. Additional lab trials and in field testing of the smaller beta type tool [field ready] with a modified more corrosive resistant actuator took place in the 4th calendar quarter of 2002 through 2004 and were successful. Additional tool modifications were made through out the 2002-2004 test period which resulted in more efficient tool to casing seal cups, ` 50% miniaturization of tool and components affording size/ weight reduction of the technology and potential application for a broader application in more wells of 3.0", 4.0" and 5.0" diameter. This work was conducted by BEDCO as part of its on going commitment to establish working G.O.A.L. Tool technology to assist in the production of gas and oil from the nations aging stripper wells. This work was supported by the SWC and NYSERDA in a follow on award for field trials of 7 G.O.A.L. PetroPump Tools.

The cost of the G.O.A.L. PetroPump and the attendant well head modifications in comparison to the 1.5X to 4.0X + improvements of gas production achieved by the beta-type [field ready] tools, at current market prices of \$5.00+ Mcf, indicate a potential payback on capital investment of less than 1 year.

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INTRODUCTION

The following is the final report under DOE NETL Prime Award No. DE-FC26-00NT41025, Subcontract No.2052-BEDC-DOE-1025 V-3 on the development of a prototype tool and beta type tool for the automatic lifting of brines with subsequent improved gas flow production from watered out stripper wells. This feat is accomplished through the use of an on tool automated pressure-sensing/ actuating valve that is preset to pass through a predetermined volume of brine with subsequent lifting of that brine to a surface process unit and brine tank. The energy for that lift is powered solely by in well geologic formation pressure.

EXECUTIVE SUMMARY

More than 8% of the US natural gas production is derived from “Stripper Wells” [A stripper well by definition is < 50 MCFD] currently averaging approximately 15-mcf/ day or ~ 1.5 TCF/ year. Much of the United States and the world’s natural gas producing wells suffer from declining and restricted production due to the presence and build up of brines in the well bore. Stripper oil wells in the lower 48 states supply 15% of domestic oil consumption. Total numbers of stripper oil and gas wells was quantified in 2003 as~ 650,000. In total ~ 18,000 oil and gas stripper wells were abandoned in 2003 with a lost oil and gas value in excess of \$530,000,000. Over the past 12 years the lost value of abandoned/ plugged wells is equal to \$6.5 Billion dollars and a projected 35,000 associated job losses, according to the IOGCC 2004. This loss and abandonment is in part related to the fact that conventional techniques for addressing and or removal of the brine and total fluids are cumbersome and costly. The scope of this project was to develop an alternative technology [total fluids pump] for the automatic lifting of that brine/ fluid to the surface using in well down hole pressure to activate an in tool valve. This sensing control valve is automatically held open by an internal pressure sensing mechanism allowing the tool to drop into the fluid column in the well. Passage ways through the tool allow passage and accumulation of brine/ fluids atop the tool to a preset column thickness at which time the on tool pressure sensing mechanism closes the tool valve. This closure is accomplished via the combined hydrostatic pressure of the brine atop the tool and system backpressure. An in well down hole seal of the tool to the casing is accomplished by a set of dual flex cups which surround the tool and make circular contact [seal] with the well casing. Subsequently tool and fluid column are lifted to the surface driven by below tool formation pressure [in well below tool pressure].

In the work completed to date on this project BEDCO has confirmed the need for and applicability of an automated tool, which will remove, accumulated fluids [brines] from gas wells and increase gas flow. BEDCO has confirmed these needs and results of increased gas yield post brine removal from wells via meetings, work sessions, well records review, interviews with well field owners and operators and preliminary production response from predecessor tools. These owners and operators currently use sundry methods of brine removal to produce gas from their stripper wells. Interviews with both well owners and operators speak to a common problem in production of natural gas from stripper wells using conventionally available techniques. That problem being, that current production techniques and tools for removal of fluids [Brines, condensate and oil] leads to intermittent and often irregular production of gas from stripper wells and certain process unit problems such as winter icing. A need for regular automated fluid removal and more uniform gas production is desired and needed.

BEDCO has produced and bench tested a prototype and beta type tools to meet industry needs and simulated in field testing with a 98% adherence/ correlation to the designed tool plan. The GOAL Pump Beta tool in field testing of 7+ wells has produced ever increasing reliability of the tool and tool system, achieving 1.5X to 4.0 X improved gas production.

BEDCO has further defined the numbers and types of wells applicable for such an automated tool through technical work and review sessions evaluating tens to hundreds of “stripper wells’ production records with a regional natural gas producers and meetings with State and Regional organizations who maintain Stripper Well records. The number of wells for which the technology is applicable in the Appalachian Region alone, in the tools current configuration [i.e. sized for 4 inch ID wells], are numbered in the high thousands. Application through out the country coupled with further miniaturization of certain tool components, indicates wells for which the technology is applicable number into the tens of thousands perhaps 100,000 or more.

The completed work on bench tools, prototype and beta type tools for field use has focused on tool design and construction of durable materials that are tolerant of down well physical and chemical conditions. To that end materials of construction are Hastelloy, 316 stainless steel for all tool body parts and condensate tolerant synthetics materials for tool sealing cups and automated valve seats. Tooling and machining of components, assembly processes for components and current generation production prototypes are so configured to match with or lend themselves to standard oil and gas field specifications and conditions of service tool [s] availability and technician capability. A field demonstration beta type tool of 32” in length and 42# of total weight has been manufactured and was bench and field tested in more than 7 wells to determine performance characteristics and simulate as well as characterize in well/ in field-testing. Installation for this new beta tool design was first deployed in a chosen Lenape Resources Inc. natural gas well, LRI # 52. This occurred in March 2002. The well physical characteristics are show in Table 1 - 1 in the Appendix. Since that time of initial testing, the beta tool has been deployed in 11 wells.

It has been determined from predecessor [larger] tool testing that variable tool response is necessary to optimize the performance to low pressure wells [< 100 psi] and low volume fluid production [< 2 bbls/ day] from certain stripper wells. To address such needs BEDCO developed bench test apparatus for mock up tool configurations to simulate and address the need for variable stroke and valve seat configuration design to address variable well conditions related to geology conditions and life cycle of the well. Further this apparatus has been and is used to calibrate assembled tools for in field-testing and post field testing wear analysis. As noted previous, in field tool testing with prior generation pilot tools has confirmed this need and ability to adjust the tool to wells with lower down hole to well head pressure differentials and small [$\sim 1/3$ bbl or less] brine [fluids] loads. It is also apparent from this testing that smaller [miniaturized] pressure sensor control mechanisms would allow for construction of a smaller tool and accommodate a wider selection of candidate wells and tool configurations. Producers express interest for a 2” to 2.5” diameter tool. Current evaluation of available materials and gas fluid lift ratio suggest a 3.0” OD tool could be developed and successfully deployed with some evolution of the technology and materials for in well/ down hole use.

Development of real time metrics which will quantify the results of the tool deployment and in well testing as well as provide detailed information for refinement of construction and operation of the tool were critical to the project success. We have determined that the oil and gas industry has begun to address these needs with a limited number of first generation continuous data loggers targeted to collect some of the key pressure and flow data associated with operating wells. BEDCO has further ‘in field” deployed and initiated configuration of such data logger units on a test well [s] to confirm its use and applicability to the “Prototype Tool and Beta Type tools”.

EXPERIMENTAL

SIMULATION AND ANALYSIS

Analytic modeling was developed to assess candidate fluid lift pump configurations. Analytic simulations indicated that the pressure at which a sensor controlled valve will close is controlled, to a first order, by the sensor-actuator compression ratio, spring force plus valve and shaft weight, and the initial sensor-actuator charge pressure and charge temperature. Additionally it was concluded analytically, that the pressure at which a sensor-actuator controlled valve will open, once closed, is related, to a first order, only to the ratio of the sensor-actuator cross-sectional area to the valve cross-sectional area, the pressure above the valve, and the pressure below the valve. Based on these understandings, various valve and sensor-actuator geometry were analyzed and alternative configurations and operating strategies were evaluated.

DEVELOPMENT TESTING

A development test program was designed to correlate the analytic modeling and to provide calibrations for development of fluid lift pumps.

The test vehicle consisted of a tubular section containing, and supporting, a sensor-actuator assembly. This was attached to a cylindrical valve seat assembly. A valve shaft was attached to the lower [free] end of the sensor-actuator in such a way that as gas pressure [forces] compressed the sensor-actuator the valve head was pulled up into the valve seat. Upper and lower pressure caps were attached to the cylindrical assembly. Bottled nitrogen plus control valves and gauges completed the test set up. Testing was also conducted with test items immersed at pressure under water. The results indicate no significant difference between water and air [gas] testing.

Tests were initiated with the sensor-actuator-controlled valve in the open position. Gas pressure was increased below the valve, filling and pressurizing the total test vehicle, until the sensor-actuator assembly compressed closing the valve. This simulated the fluid pump descending into the well, being exposed to the flow pressure and hydrostatic fluid pressure, and eventually shutting in the well. The testing established the validity of the analytic modeling of in-well valve closing providing an analytic basis for design modifications.

Each test was continued to simulate the fluid pump arriving at the well head. The pressure above the sensor-actuator-controlled valve was bled off; corresponding to that which would be dissipated into the tank and sales line as the fluid pump approached the surface. The pressure above the sensor-actuator, in the test vehicle, was varied parametrically from one to five atmospheres to assess the validity of the analytical modeling. The pressure below the valve, and sensor-actuator, was reduced until the valve opened. This represented the reduction of well flow pressure that would result as the gas was discharged from below the liquid pump. Once again, the experimental data was in good agreement with analytic predictions of the conditions necessary for valve opening. Analytic modeling was used to evaluate alternative fluid pump designs and operating strategies.

FLUID PUMP CONFIGURATIONS

Two sensor-actuator diameters and several valve head configurations were tested over a range of simulated operating conditions. A liquid pump design was tentatively selected, fabricated and tested. Sensor-actuator compression ratios were varied (stroke adjustments) and sensor-actuator charge pressures were selected parametrically to characterize the liquid pump development model. Figure 1 represents sample results of development testing for the selected configuration (hundreds of test have been conducted with a variety of configurations).

Table 1 Gas Operated Automatic Liquid Pumping System (fluid pump)

Bench testing of TOOL #1 with a reduced stroke.

August 10, 2001

Summary: Calibration testing of Tool #1 was conducted with a reduced stroke of about 1.05"

Test Results: (Pressure are PSIG)

Stroke about 1.05 inches (+/- .02")

| Charge Pressure | Valve Closing Pressure | Pressure above Valve At Valve Opening | Opening Pressure | Absolute Pressures Calculations | | | | |
|-----------------|------------------------|---------------------------------------|------------------|---------------------------------|--------|-------|-------|-------|
| | | | | Pcharge | Pclose | Popen | Po/Pc | Pa/Pc |
| 20 | 58 | 20 | 32 | 34.70 | 72.70 | 46.70 | 0.64 | 0.48 |
| 20 | 58 | 0 | 20 | 34.70 | 72.70 | 34.70 | 0.48 | 0.20 |
| 20 | 55 | 0 | 18 | 34.70 | 69.70 | 32.70 | 0.47 | 0.21 |
| 20 | 56 | 0 | 18 | 34.70 | 70.70 | 32.70 | 0.46 | 0.21 |
| 20 | 55 | 30 | 40 | 34.70 | 69.70 | 54.70 | 0.78 | 0.64 |
| 20 | 55 | 30 | 40 | 34.70 | 69.70 | 54.70 | 0.78 | 0.64 |
| 20 | 57 | 20 | 32 | 34.70 | 71.70 | 46.70 | 0.65 | 0.48 |
| 30 | 70 | 30 | 43 | 44.70 | 84.70 | 57.70 | 0.68 | 0.53 |
| 30 | 70 | 30 | 44 | 44.70 | 84.70 | 58.70 | 0.69 | 0.53 |
| 30 | 73 | 30 | 44 | 44.70 | 87.70 | 58.70 | 0.67 | 0.51 |
| 30 | 70 | 50 | 59 | 44.70 | 84.70 | 73.70 | 0.87 | 0.76 |
| 30 | 70 | 60 | 65 | 44.70 | 84.70 | 79.70 | 0.94 | 0.88 |
| 50 | 106 | 50 | 66 | 64.70 | 120.70 | 80.70 | 0.67 | 0.54 |
| 50 | 107 | 30 | 51 | 64.70 | 121.70 | 65.70 | 0.54 | 0.37 |
| 50 | 107 | 20 | 42 | 64.70 | 121.70 | 56.70 | 0.47 | 0.29 |

In all testing, the calculated absolute pressure ratios (that is, valve opening pressure/valve closing pressure, and pressure above the valve at opening/valve closing pressure) can be characterized by a straight line plot, the slope being determined by the ratio of the sensor-actuator effective cross-sectional area to the valve seating cross-sectional area.

Specifications have been developed for the fabrication of two alternative sensor-actuator configurations; one with a reduced diameter (1.70" vs. 2"), and both with longer available strokes (20% increase). Discussions are in process with suppliers.

RESULTS AND DISCUSSIONS

The project has been broken down into six major tasks. Those work tasks and the status of activities on those tasks are outlined below:

1.0 COMPLETE DESIGN OF PROTOTYPE TOOL

- 1.1 The project senior engineering, senior manufacturing and scientific personnel have conducted meetings and work sessions with field engineering/ well operations personnel to outline field durability needs, assembly, adjustment, ease of installation and service specifications for the prototype tools. Findings indicated the obvious needs for chemical compatibility with down hole chemistry. This is addressed via the use of Hastelloy, 316 stainless steel - metallurgy and valve seat and sealing cup chemistry that will be tolerant of both brine and condensate. Additional findings go to near term application of the tool in 4 inch casing wells and longer term application of tool use in tubing of 3.0 inch and 5.0" cased wells. Immediate needs for the 4 inch cased wells addressed tool total weight, total length, and assembly/ deployment/disassembly of tool components in the field.
- 1.2 Specific elements that have been addressed are the length, weight and tool diameter to allow for maximum use in varying type of wells and minimum amount of reconfiguration of well head and associated cost. Ancestral tools were in excess of 5 to 6 feet in length and 70 to 105 pounds in weight. Operating BEDCO predecessor prototypes were 46 inches in length and weighed to ~54 pounds. The tool constructed and bench testing for deployment and testing for the SWC 2002- 2004 project [7-Beta Tools] is 32" in length and weighs ~ 42 pounds. This design and construction configuration allows ease of deployment of the G.O.A.L. PetroPump and retrieval by a well tender with minimal changes in configuration to a typical well head lubricator.
- 1.3 Another specific element determined in field meetings for tool modification is the component assembly characteristics. Field assembly, disassembly and adjustment must be possible with the fewest number of field tools and personnel to assist. To that end, tool design and construction has been simplified and addressed to oil and gas industry standards. This includes only three- [3] field serviceable disconnects and these are constructed with standard 6 pitch General Acme threads. Components have been reduced from 50 or more on ancestral tools to 27 or more [54" tool] in immediate predecessor tools to 14 for the 7 field tested Beta tools. Basic material for the tool body is commercially available Hastelloy [TM] and durable 316 stainless steel. Minimum steps for tool assembly and large milled tool flat areas [wrench flats] complete the simplified design and assembly. This design/ construction/ assembly approach all lends itself to service and maintenance work by standard industry tools [i.e. 36" and 48" pipe wrench, 18" and 24" adjustable wrench and 3# and 5# hammer].
- 1.4 Field and bench testing has lead to further tool modification of valve seal mechanism [fixed alignment of valve seats], actuator durability and miniaturization, new compounding and configuration of seal cups improving simulated and field confirmed results with the SWC new designed and field tested tools.
- 1.5 Project senior engineering, manufacturing and scientific personnel have conducted work sessions and have completed prototype and beta type tools in conjunction with the specialized machining firm of Eagle Tool and Die. The tools completed bench testing and well simulation testing. The, "user friendly", smaller tool was installed in a test well[s] in March 2002 through end of 2004. To achieve the above referenced reduced size and weight of tool, senior engineering designed for the use of a new design and constructed [20 % smaller diameter] self actuating control mechanism for

the automated control valve. This major change in design and construction fostered other reductions and size leading to the decreased tool length of ~15" from predecessor tools @ 54" to the current 32" prototype/ beta type tools for SWC in well demonstration and decrease in weight of ~12 pounds to a current weight of ~42 pounds. These represent significant changes, which lend them self to one-man installation and ease of use and retrieval. Tool drawings and list of materials stock for machining of components and assembly have been simplified in form and reduced in total numbers of components to 14 from 27. The drawings and materials stock list are completed. The documents have been reviewed by the joint team to determine the possibility of further simplification and reduction in component parts. Valve actuator corrosion protection and protection against over-pressurization from ambient forces down well was determined as factors in tool operations and design/ construction compensated.

- 1.6 Project senior engineering in conjunction with the manufacturing director have designed, constructed, modified and refined a bench testing device on which the prototype and beta type tools have and were tested prior to and post in field testing. Lab testing of varying pressure [equating to differing in well brine head/ pressure] simulations has been tested to confirm viability and operational integrity of the constructed bench testing equipment and tool critical components. Changes in the actuator stroke and seating area of the self actuating valve assemble have been subject to test to allow for and confirm potential for operation in low pressure and small brine volume/ fluid load environments.

- 1.7 Specifications and modifications to the pressure sensing [valve control] device for the operation of the in tool automatic valve have been developed from the above completed meetings, work sessions and test stand work with specific reference to targeted installation wells.

2.0 CONSTRUCT AND BENCH TEST PROTOTYPE/ BETA TYPE TOOLS

- 2.1 The prototype and beta type tools were constructed and bench tested against design parameters to which it adhered with greater than 98% correlation. The tools were "in lab modified" to accommodate learned information from predecessor and on going field test to avert over pressurization by ambient forces in down hole conditions. Well operation simulation testing is on going as part of company QA/QC and product evolution on tools retrieves post field testing.

3.0 SELECT CANDIDATE WELLS

- 3.1 Meetings and work sessions with Lenape Resources Inc. Seneca Resources, Cotton Well Drilling, Chatham Resources and RMOTC and others have been conducted to assemble a list of candidate wells and choose wells for testing of the "Prototype Tool" and Beta Type tools.
- 3.2 Starting with a list of more than 300 operating and shut in stripper wells a short list of more than 50 wells was assembled. This short list was further refined to ~ 12-15 target wells. From those alternative wells, LRI # 52 and # 29 were chosen for initial Prototype/ beta type tool testing with many of the other wells referenced above chosen for Beta type tool testing.
- 3.3 Considerations evaluated in choosing LRI # 52 and LRI 29 include total yield over time since completion, current yield, and history of fluid production, decline curves and previous testing database.

- As noted above, two alternative test wells were initially considered. LRI # 52 and LRI #29 were subsequently both evaluated for initial field tool use and evaluation.
- Data on these wells is shown in the appendices
- LRI # 52 had been previously tested with predecessor [54" larger tool] tools, a standard casing swabs, small diameter tubing and has the most complete available history of technical data for evaluation and comparison of the many variables associated with gas production which makes it a technical favorite for testing and analysis. The well however is associated with a sales/ gathering system which periodically [especially during low commercial gas demand] that pressures up to in excess of 100 psi [~ equal to down hole pressure] versus normal operating pressures of 50 psi making gas production from the well under those conditions onerous to not possible.
- Well LRI # 29 as a candidate has less data base and history of close watched operations, but has an advantage of being produced into a sales line with an LRI owned/ operated compressor station which theoretically can minimize wide/ wild swings of back-pressure on the system to 40 psi or less.

3.5 Associated data on water/ brine production on these wells and other back up candidate wells was and continues to be assembled along with well response [production] information related to intermittent or regular removal of those brines. The final choice of initial test well[s] was made upon data review and completion of tool assembly with in field-testing initiated in March of 2002 to current on well # 52 and shortly thereafter on well LRI- 29. The additional 9 wells tested were done so in 2003 and 2004 after further tool modification resultant from initial test on the LRI wells.

4.0 TEST WELL PRODUCTION

- 4.1 Quantification of gas production before, during and post "Prototype Tool" deployment is a key element on the development of metrics to confirm applicability and success of the tool. Current technology on most wells for quantification of gas yield and pressure is performed by analogue instrumentation. This analogue instrumentation is tied to a specific orifice plate size in the well process unit and recorded on a circular 'pie' chart. The charts are subsequently integrated and quantified by third party off site contractors at a later date.
- 4.2 The project scientist and engineers assembled some of this analogue data as it relates to the first target well for in field-testing and continue to assemble review and interpret this historic data. Production from this well meets targeted test parameters. Those parameters include down hole pressure and historic production challenges which between the period of 1994 to 1999 showing low to no gas production from this well # 52 prior to physical swabbing / brine removal with a work over rig to remove several tens of barrels of brine.
- 4.3 In field process production data from a larger BEDCO [54" tool] and even larger/ heavier predecessor tool also underwent analysis and was used in final fabrication of the SWC prototype test and beta type test tools and wellhead modification parameters. Reduced data to date from this predecessor tools shows an increase gas production from [2] two different stripper wells of >1.6X to 2.4X. Regular tool automatic cycles at 1 cycle each 1-1.5 days with 0.3 to 0.8 barrels of fluid produced per cycle @ 15 to 20 cycles/ month yielding 8 to 10 barrels/ month of brine are recorded. In well and at well head operating conditions evidence typical pressure

ranges expected for the SWC - 7 well test of 50 to 60 psi backpressure [sales line] and down hole pressure conditions of 100 to 150 psi.

- 4.4 Real time comprehensive data collection of well head, process unit and sales line pressure and flow are critical to thorough comprehension of well and tool operation. To that end BEDCO has acquired, modified and deployed a digital recording data logger[s] to capture this type of information. Digital data loggers can collect comprehensive “real time” data at the well head and the process unit. Technical information was first assembled on manufactures and suppliers of continuous recording digital data loggers [well head computers] to collect and log both volume yield and pressure through out the well head and process unit system.
- 4.5 Bids were solicited for the purchase of a unit most applicable to project needs.
- 4.6 A successful bidder/ supplier of the well head data logger was selected. The unit wellhead computer, solar panel and battery was purchased installed and field-tested.
- 4.7 The components of the unit have been field installed on a chosen data collection/ confirmation well in the Lenape Resources System. Unit software and sensors have been installed and calibrated. Results to date show accurate relative correlation with analogue recording charts [for delta P of < 20”] on the well and the ability to collect and recorded data in digital form on as frequent as 1-minute intervals. Down load of system data via cellular link has been proven viable. Soft ware challenges in manipulating the data for accurate/ absolute correlation/ comparison on a 1 to 1 basis were worked on by BEDCO and the equipment manufacturer to achieve in field data collection/ recording and telephonic down loading success.
- 4.8 Significant insight into post tool run production was gained from detailed analysis of the data logger results. The normal analogue charts system for well 52 and well 29 use orifice plates tied to an analogue chart which can record 20” of pressure differential which is recorded as an inked line on a pie chart. Volume of gas produced by the well is determined by integrating the area under the curve recorded on the chart. Off chart reading [>20”] are not recorded and cannot be quantified. Post GOAL tool lifts of fluid, the data logger recorded pressure differentials of 200- 300” for period of 15 minutes to 1 hour resulting in **non quantified** gas of ~ 0.5 to 1.5 M or more of gas / cycle of tool. This observation indicates that wells using standard analogue recording pie charts may not record several 10’s of Mcf/ month for the well in which the tool is employed. For wells like LRI- 52 which makes 20-60 or more runs/ month this can equate to more than \$1000/ year to several thousand in non quantified revenue at the well head. Down sales line master meter systems with larger scale metering units can capture and quantify this produced gas as part of a network of wells but not for the well tested. As such results achieved for well # 52 are bias low.
- 4.9 Preliminary field recorded data has been retrieved, downloaded and formatted for correlation with the analogue data from the well. An example of incremental data being recorded is presented in Figure 2. Daily summary data is also available.

Table 2

HOURLY REPORT

FLOW AUTOMATION CORP.

HOUSTON, TEXAS

DATE: 08/03/01

METER NAME: METER RUN #1

TIME: 05:20:33

CONFIGURATION DATA

| | | | | | |
|------------------|---------|------------------|--------|-------------------|------------|
| Contract Hour | 08:00 | Spec. Gravity | 0.6 | Mole % CO2 | 0.0 |
| Mole % N2 | 0.0 | Energy Content | 1000.0 | Pipe Diameter | 1.987 |
| Orifice Bore | 0.375 | Tap Config. | Flange | Tap Location | Downstream |
| Temperature Base | 60.0 | Pressure Base | 14.65 | Atmos. Pressure | 14.7 |
| Low DP Cut-Off | 0.5 | Fpv Method | AGA8 | Gross 2530 Method | 2530-1992 |
| Fwv Method | Manual | Fwv Factor | 1.0 | Water Content | 1.0 |
| Well Stream | Enabled | Well Stream Val. | 1.0 | | |

| DATE | TIME | VOLUME MSCF | ENERGY MMBTU | AVG SQRT (DP * AP) | AVG. DP IN H2O | AVG. P PSIG | AVG. T DEG. F |
|----------|-------|----------------|-----------------|-----------------------|-------------------|----------------|------------------|
| 07/17/01 | 08:00 | 0.1699 | 0.1699 | 9.18453 | 1.31 | 51.6 | 1.89 |
| 07/17/01 | 08:30 | 0.1874 | 0.1874 | 9.71828 | 1.47 | 51.46 | 1.86 |
| 07/17/01 | 09:00 | 0.1871 | 0.1871 | 9.68400 | 1.46 | 51.3 | 1.84 |
| 07/17/01 | 09:30 | 0.1874 | 0.1874 | 9.68333 | 1.47 | 51.02 | 1.79 |
| 07/17/01 | 10:00 | 0.2043 | 0.2043 | 10.45441 | 1.73 | 50.06 | 1.62 |
| 07/17/01 | 10:30 | 0.1855 | 0.1855 | 9.60922 | 1.49 | 49.5 | 1.51 |
| 07/17/01 | 11:00 | 0.1714 | 0.1714 | 9.05914 | 1.32 | 49.46 | 1.5 |
| 07/17/01 | 11:30 | 0.1781 | 0.1781 | 9.23295 | 1.36 | 49.73 | 1.54 |
| 07/17/01 | 12:00 | 0.1902 | 0.1902 | 9.81453 | 1.53 | 50.06 | 1.59 |
| 07/17/01 | 12:30 | 0.1855 | 0.1855 | 9.48633 | 1.43 | 50.07 | 1.58 |
| 07/17/01 | 13:00 | 0.1693 | 0.1693 | 9.09532 | 1.32 | 50.15 | 1.6 |
| 07/17/01 | 13:30 | 0.1245 | 0.1245 | 8.77455 | 1.22 | 50.9 | 1.73 |
| 07/17/01 | 14:00 | 0.1014 | 0.1014 | 7.63768 | 0.87 | 53.57 | 2.2 |
| 07/17/01 | 14:30 | 0.2102 | 0.2102 | 10.66151 | 1.69 | 54.2 | 2.32 |

- 4.10 The "Data Logger" programming is being further addressed to provide more application to project needs.**
- 4.11 Software and formatting components were reviewed and modified to meet project data needs. Additional considerations for future use include transducer outputs and event indicators (surface arrival and departure of the fluid pump) are being considered for incorporation in the status reports.**
- 4.12 Data contained in Table # 3 was obtained via cellular down load connection with well #52 shows significant post tool run/ non quantified gas production readings referenced earlier in this report. Follow on tool run pressure and gas production increase significantly. Follow on pressure spiked at more than 300" of delta P and follow on gas production was >1 order of magnitude greater than normal production. The net results was produced gas that is not quantified by the standard analogue pie chart recording and accounting methodology employed on this and many wells. During just 1 period of 15 minutes noted on the chart below, the well produced > 1 mcf of gas which was not quantified on the analogue production [pie] chart. This well makes 20-60 tool runs/ month under variable line pressure conditions. This can equate to > \$1,000 to \$2,000, perhaps more/ year @ \$5/ mcf in non well head quantified gas produced by this well with the aide of the GOAL Pump.**

Table 3

HOURLY REPORT

FLOW AUTOMATION CORP.
HOUSTON, TEXAS

METER NAME: METER RUN #1

DATE: 02/17/03
TIME: 11:33:34

CONFIGURATION DATA

| | | | | | |
|------------------|---------|------------------|------------|-----------------|-----------|
| Contract Hour | 08:00 | Spec. Gravity | 0.6 | Mole % CO2 | 0.0 |
| Mole % N2 | 0.0 | Energy Content | 1000.0 | Pipe Diameter | 2.0 |
| Orifice Bore | 0.375 | Tap Config. | Flange | Tap Location | Upstream |
| Temperature Base | 60.0 | Pressure Base | 14.65 | Atmos. Pressure | 14.7 |
| Low DP Cut-Off | 0.1 | Fpv Method | AGA8 Gross | 2530 Method | 2530-1992 |
| Fwv Method | Manual | Fwv Factor | 1.0 | Water Content | 1.0 |
| Well Stream | Enabled | Well Stream Val. | 1.0 | | |

| DATE | TIME | VOLUME MSCF | ENERGY MMBTU | AVG SQRT (DP * AP) | AVG. DP IN H2O | AVG. P PSIG | AVG. T DEG. F |
|-----------|-------|----------------|-----------------|-----------------------|-------------------|----------------|------------------|
| 02/16/03 | 20:00 | 0.0105 | 0.0105 | 3.35824 | 0.18 | 45.22 | 60.0* |
| 02/16/03 | 20:05 | 0.0082 | 0.0082 | 3.12864 | 0.16 | 45.26 | 60.0* |
| 02/16/03 | 20:10 | 0.0090 | 0.0090 | 3.03070 | 0.15 | 45.41 | 60.0* |
| 02/16/03 | 20:15 | 0.0106 | 0.0106 | 3.40009 | 0.19 | 45.55 | 60.0* |
| 02/16/03 | 20:20 | 0.0052 | 0.0052 | 2.84323 | 0.13 | 45.64 | 60.0* |
| 02/16/03 | 20:25 | 0.0110 | 0.0110 | 3.48820 | 0.2 | 45.68 | 60.0* |
| 02/16/03 | 20:30 | 0.0062 | 0.0062 | 3.00309 | 0.15 | 45.6 | 60.0* |
| 02/16/03 | 20:35 | 0.0091 | 0.0091 | 3.36188 | 0.18 | 45.6 | 60.0* |
| 02/16/03 | 20:40 | 0.0089 | 0.0089 | 3.33204 | 0.18 | 45.55 | 60.0* |
| 02/16/03 | 20:45 | 0.0038 | 0.0038 | 2.82458 | 0.13 | 45.48 | 60.0* |
| 02/16/03 | 20:50 | 0.0088 | 0.0088 | 2.89528 | 0.13 | 45.45 | 60.0* |
| 02/16/03 | 20:55 | 0.0016 | 0.0016 | 2.64288 | 0.11 | 45.37 | 60.0* |
| 02/16/03 | 21:00 | 0.0100 | 0.0100 | 3.23950 | 0.17 | 45.33 | 60.0* |
| 02/16/03 | 21:05 | 0.0050 | 0.0050 | 3.15191 | 0.16 | 45.33 | 60.0* |
| 02/16/03 | 21:10 | 0.0077 | 0.0077 | 2.97227 | 0.14 | 45.27 | 60.0* |
| 02/16/03 | 21:15 | 0.0103 | 0.0103 | 3.40718 | 0.38 | 45.28 | 60.0* |
| >02/16/03 | 21:20 | 0.4474 | 0.4474 | 153.5163 | 344.86 | 58.77 | 60.0* < |
| 02/16/03 | 21:25 | 0.3548 | 0.3548 | 118.7151 | 207.49 | 54.05 | 60.0* |
| 02/16/03 | 21:30 | 0.2077 | 0.2077 | 67.95721 | 74.42 | 49.08 | 60.0* |
| 02/16/03 | 21:35 | 0.1158 | 0.1158 | 37.47577 | 23.2 | 47.09 | 60.0* |
| 02/16/03 | 21:40 | 0.0776 | 0.0776 | 25.04038 | 10.39 | 46.37 | 60.0* |
| 02/16/03 | 21:45 | 0.0542 | 0.0542 | 17.4571 | 5.04 | 45.99 | 60.0* |
| 02/16/03 | 21:50 | 0.0506 | 0.0506 | 16.28565 | 4.38 | 45.87 | 60.0* |
| 02/16/03 | 21:55 | 0.0408 | 0.0408 | 13.1133 | 2.87 | 45.8 | 60.0* |
| 02/16/03 | 22:00 | 0.0409 | 0.0409 | 13.13788 | 2.88 | 45.84 | 60.0* |

- 5.0 Well # 52 tool installation of the Beta tool [32" tool] took place in March of 2002 with, testing of two different tools in March through November of 2002. Gas gathering system pressure back up / increases in sales line backpressure were coincident with tool installation in March of 2002 and made initial tool runs and data interpretation awkward. Sales line compressor shut down [s] and service work effectively "pressured out" the tool from running for the first several weeks of operation and testing. During this period line pressures measured at 65 to 70 psi. Well head shut in pressures for # 52 during this same period measured as low as 85 psi. In general a 10

- 12-psi pressure differential between well and sales line is required to operate the tool. Note: This is as comparison to a typical 70-90 psi pressure differential needed for tubing plungers/ rabbits]. Tool runs during this period were sporadic and variable in terms of fluid production and post tool run gas production. Fluids production with tool runs [first tool] varied from 0 [zero] to 0.33 Bbls per run. Gas production for the period varied from a high of 14 mcf/d to a low of 7 mcf/d. At the maximum value the gas production and fluid production were similar to the predecessor first prototype BEDCO tool and much higher [>60%] than the standard casing plunger used in this well in 2000 and previous years and a considerable multiple over the unassisted production of 4-5 mcf/d by natural flow. At the low production of 7 mcf/d the tool and well were producing on average 1 mcf/d less than the average production achieved by the standard casing plunger. All yields were greater than production historically achieved using tubing alone which achieved 3-5 mcf/d.

- 5.1 Observations on the first generation beta tool runs, brine production and gas production from well # 52 during this period of unusually unstable line pressures over several months indicated a general decline in fluid production and decrease in gas production post each tool run. In all two different tools [the second tool at BEDCO cost and expense, as it was not budgeted for in the SWC work plan] were subject to in well/ in field-testing. Both evidenced a similar pattern of performance in well # 52. As such, this portion of the test was reluctantly terminated in early August of 2002 and the tools were returned to BEDCO facility for preliminary evaluation. Physical observations of the prototype tool valve assembly indicated a misalignment of the valve and valve seat. This mis-alignment appeared to stem from the size reduction efforts, which removed certain valve stem guides. This misalignment alone did not preclude tool operations when bench tested both pre and post well installation and operations. The second more profound discovery of ex-situ well, in laboratory, testing was the appearance of slow pressure loss from the actuator assembly. This pressure loss was observed to occur over a period of hours to days on the tools used and retrieved from well # 52. As the actuator is a sealed system, the immediate source of the leakage/ failure was not readily apparent. The actuators were returned to the manufacturer for destructive analysis testing. Upon arrival at the manufacturer, the actuators were first re-subjected to a water bath pressure test to confirm absence of integrity as found in the BEDCO facility. Confirmation of pressure leakage from the assembly was made. The actuators were subsequently disassembled and examined under high magnification. This examination revealed corrosion holes in the actuator. The location of the corrosion holes were located on the stainless steel side of a Hastelloy- stainless weld line. Both tool actuators showed a similar failure pattern. Research into the problem shows an elevated corrosion index potential between Hastelloy and stainless steel metals. This corrosive potential in the construction of the actuator was compounded by the welding of the stainless steel to the Hastelloy and certain physical restrictions in the fluid passage through the actuator which caused brine [15 – 20 % NaCl] to accumulate adjacent to the welds where the corrosion effects were concentrated.
- 5.2 A further design change and manufacturing change was made in the tool actuator to off set corrosion problems. This tool w/ new built actuator was constructed and sent to well #52 in late August of 2002
- 5.3 Performance of the tool started as designed with ~ 1 Bbl of fluid per cycle and an approximate 60% gas increase. Cycle frequency deteriorated and yield declined. The tool was removed for lab testing in Late November. Preliminary evaluation shows no corrosion problems but a mechanical binding of actuator components. It should be noted herein that upon completion of each test of the 32" tool in LRI # 52, the predecessor 51" tool was re-deployed to confirm function of the TOOL in well # 52,

absence of any changed conditions and the applicability of the design. Each time the 51" tool quickly stabilized production and tool cycling and fluid removal. Tool cycle frequency is generally at 1 to 1.5 days with production of 0.75 to 1 Bbl of brine and increase gas yield to 12 to 15 MCF for the well vs previous at 7 mcf or less.

- 5.4 January of 2003, a 4th Beta type tool was manufactured and installed in well # 52. This tool incorporated components and elements of previous tested tools in a slightly altered physical format. The tool actuator was set to retrieve ~ 1Bbl of fluid/ tool cycle under operating sales line back-pressure of ~50 psi. The tool performance was as targeted by the design and in keeping with bench test results. The well produced approximately 0.75 to 1 barrel of brine per cycle with back-pressures in the range of 50 to 60 psi. Yield at the well was recorded at 12 to 14 Mcf/d as compared to previous 6 to 7 Mcf/ d averages.
- 5.5 Well # 29 tool installation [32" tool] initially took place in July of 2002. The tool was installed in a well, which was plumbed to a gathering line with its own compressor system which theoretically should have been able to maintain a stabilized pressure. Manpower limitations in service of the compressor plagued the operation for the first 4-6 weeks of the test. Operating pressures were subsequently stabilized and the tool made several automated runs. The first of the runs was at the targeted fluid removal rate of 0.75-1.0 barrels/ run with subsequent runs at lesser quantities of fluid until the tool ceased automatic operation. The tool was retrieved via blowing the well to the brine tank and catching the tool in the catcher built into the lubricator. No external assistance was required to retrieve the tool.
- 5.6 Bench test analysis proved to show lost pressure in the well # 29 tool actuator. Destructive analysis of the actuator proper revealed a corrosive failure at the Hastelloy/ Stainless interface as with the 1st and 2nd tools deployed in well IRI-52. The redesign and reconstruction of the actuator as noted for well LRI # 52 was developed and was further refined for further in filed successful testing.
- 5.7 Tool design modifications were made. These modifications include a support mechanism for the valve and valve seat assembly, which improved alignment and increase concentricity of valve and seat in the tool. This further reduced potential for seating problems or leakage of the valve once closed and sealed. The more important remedy is a metallurgy change in the contact area [reduce corrosive index potential] between the stainless steel end fitting and the Hastelloy actuator. This metallurgy change was coupled with a physical modification to the actuator which eliminates blind passages in the tool, which can trap brine and there by concentrate their corrosive effects. BEDCO has self-funded these design modifications and manufacturing of new actuators outside of the SWC sponsorship on the project. Further mechanical modifications were warranted based upon response of the tool deployed to well LRI # 52 in August-November 2002. These design modifications were fitted to the tool with initial lab and field-testing in the first calendar quarter of 2003. As noted above the results for well # 52 were on target with design basis and bench tested results.
- 5.8 Post the determination of the first generation Beta type [smaller tool] actuator under performance in August through November of 2002, BEDCO re-installed [as noted above] a predecessor larger tool [51" tool] in well # 52 and LRI # 29 to confirm applicability of the technology. This earlier version, larger, somewhat more cumbersome, tool was deployed in late August of 2002 and again late November through December of 2002. The tool was set with an increased actuator pressure to accommodate accumulated brine not removed during the previous testing. The tool target was to retrieve 0.75+ Bbl of brine on each tool run at 60 psi of sales line back-

pressure. Observations during the month of September 2002 showed 5 to 7 tool runs per week yielding 0.75 to 1.0 Bbl of brine per trip. Gas yield after each of the trips averaged 14.5 - 17.5 mcf/d. The brine production is ~ 2 fold greater than during previous tool test and gas yields ~ 15 to 20% greater. Comments by the well tender post the old tool re-deployment were, "gee that well just gets better and better". Similar results were achieved during October through December of 2002.

- 5.9 Well # 29 was re-tested with a 51" version of the tool to confirm applicability of the technology. Testing was re-initiated in mid-January of 2003 and continued through end of year. The tool was initially set to retrieve 1.5 Bbl of brine/ tool cycle at a back-pressure of 30-35 psi. Well performance prior to G.O.A.L. tool installation was at ~ 5Mcf/d. Post tool installation, the well production increased to 10 Mcf/ day while producing 1.5 Bbl of brine per cycle. Severe cold and icing in the well head lubricator caused the tool to become lodged in the lubricator once each 2 to 3 trips. After a month of operation at the 1.5 Bbl/ trip rate of brine production, the actuator was re-set to lift 2 Bbl/ cycle of brine. Post this adjustment to the tool a 2 Bbl/ cycle was achieved and the well yield increased to a stable 13Mcf/d. This well was subsequently fitted with a beta 32" tool and achieved similar results.
- 5.10 The first Oil and Gas well tested was # 341 which was initiated using a version of the larger [51"] tool in July of 2002 to accommodate accelerated passage downward through the oil. The tool was set up for the reported operating conditions of the well to produce 3 to 4 Bbls. of fluid per cycle. Actual well operating conditions proved different than recorded and predicted. The tool made 2 partial tool runs producing small volumes of fluid [2 barrels] and then produced one run yielding 41 Bbls. of total fluids comprised of a 40/1 BBl. ratio of oil to brine. The tool was retrieved. The actuator in the tool was to be set at a lower pressure to attempt to accommodate the different [lower pressure and faster fluid accumulation rate] conditions of the well. Prior to the ability to re-deploy the tool weather conditions made access to the well non-tenable [non all weather road]. The well operator suggested postponing the test until the road was once again trafficable to remove oil and fluids produced by the tool. The tool was retrieved for use in another [to be selected] test well.
- 5.11 Additional Tool/ well testing with the newest 32" Beta tools was completed through out 2003 and 2004. The evolved tool design and construction incorporated improved metallurgy, improved seal cup formulation/ configuration, and improved internal alignment for valve seal and seat. The wells tested and results achieved are contained in the following table.

Table # 4

Evaluation of Well Performance with G.O.A.L. PetroPump

| Well designation, Geologic setting and Depth | Pre GOAL Production/ Methodology | Post/ with GOAL tool Production | Fluid Production Qty./ Frequency | Comments |
|---|---|--|---|--|
| LRI-52, Medina Fm., tight Sst @ 3300' | 4-5 mcf/d w/ tubing, - 7 mcf/d w/ standard casing swab | 13-15 mcf/d post domestic/ farm consumption and non quantified off chart production Fig. # 3 | ~4 Barrels/ week @ 1 to 4 runs daily, down hole 95 psi, - line 55 psi average | ~ \$60K+ Rev- over test period. Stable freq. runs& prod. [~230M/ month not recorded off chart and Agra business consumption] Fig. # 2 |
| LRI -29, Median Fm. tight Sst. @ 2390' | 4-6 mcf/d w/ tubing, -7 mcf/d w/ std. casing swab | 13-16 mcf/d | 1 barrel/ day, @ 1 tool run/ day-, 105 down hole psi, -line 30-35psi | Very stable production and tool run frequency- no cup changes in > 1 year, 2+ years test. Est. \$20K + Revenue |
| LRI- 332, Median Sst. @ 3350' | 3-5 mcf/d w/ tubing, 7-8 mcf/d w/ std, casing swab | 18-22 mcf/d | 3-6 Barrels/ wk. @ 1-3 runs/ day-, down hole 110-115 psi, -line 50-55psi | Tool removed- well gave back frac sand- tool retrieved w/o external assistance, tool operated ~ 9+ mo. w/ out prblms. |
| LRI- 54, Median Fm, tight Sst, @ 3250' | 3-4 mcf/d w/ tubing, 5-6 mcf/d w/ std casing swab | 5-12 mcf/d- very erratic automatic operation- always retrievable by venting to tank | 1-5 bbls/ week, irregular runs, 2/ day to 1/ week, down hole 120 psi, -line 50-65 psi | Down hole casing problem suspected with periodic loss of press. causing tool stalling |
| LRI-341, Bass Island [oil and gas] carbonate well @2800' | Pump jack- 3.5 Bbls oil/day & 3-4 mcf/d gas | Post tool runs gas not quantified- automatic runs achieved | 2- 41 Bbls/ run, - 41 bbl run [40-1 ratio oil to water] run, gas not quant.- follow on pressure @ 350+ psi | Site volume storage problems- road access problems- test terminated- tool re-deployed |
| LRI-274, Median Fm, tight Sst @ 3400' | 1-2 mcf/d w/ open hole | 6-8 mcf/d, erratic production, did not get ahead of fluid production | 1-4 bbls/ run, - down hole 400 psi, -line 60-65 psi follow on tool run pressure increasing wh. test terminated | Infrequent service during start up by well tender, well subsequently sold- tool removed |
| C-14, Red Medina, Sst @1355' | 10-15 mcf/d w/ velocity string | 15 + mcf/d insufficient frequency of data collection/ sales line pressured up to > 220 psi | Several tools run made both automatic and manual- down hole casing problems | Well tubing encrusted and of variable diameter, tool/ cup binding- infrequent runs |
| C- 35, Red Medina, Sst @ 1395" | 15- 20 mcf/d w/ velocity string | Sales line pressure max'ed @ 230 psi shortly after tool install- no compressor on line | Tool runs made by shut in well and blow to tank- down hole well diameter problems [variable/diameter] | Well tubing encrusted, inadequately scraped, casing of variable diameter- tool/ binding |

| | | | | |
|---|---|--|--|---|
| RMOTC 12-AX-11, Second Wall Creek Fm, Sand @ 3162' | 29 mcf/d w/ pump jack for fluids @ 1-2 Bbls/ day | ----- | ----- | [1]Fluid level to low- below perfs in open hole [2] pressure differential marginal @ 15-20 psi |
| | | Table 4 Continued | | |
| Well Designation, geologic setting & depth | Pre GOAL tool production/methodology | Post/ with GOAL tool production | Fluid Production Qty./ frequency | Comments |
| RMOTC 35-AX-34, Second Wall Creek Fm, @ 3017' | 1.7 BF/D & 60 mcf/d w/ pumpjack | ----- | ----- | [1]Fluid Level to low, below perfs, [2] pressure differential in sufficient |
| RMOTC 38-1AX-34 Second Wall Creek sand @ 3185' | 3.3 BF/D & 60 mcf/d w/ pump jack | ----- | ----- | [1]Insufficient fluid above safety stand to set tool [level too low] |
| RMOTC 36-MX-10, Muddy Fm, Sand @ 4063' | 1 BO/D, 5.5 BW/D & 150 mcf/d gas w/ pump jack- 0 fluids and 0 mcf/d natural flow | ----- | ----- | [1]Well prep. left residual paraffin and scale down hole- tool could not reach fluid- [2]well re-cleaned- [3]cups swell in aromatic oil- [4]new aromatic resistant cups added tool damaged on re-deploy-no seal |
| SR- 2023, Medina FM, tight Sst @ 2625' | 3-5 Mcf/d open hole w/ periodic swab production flow | 15- 25 mcf/d | 1-2.5 Bbls/ wk, @ 3-6 runs/ wk, down hole pressure @ 90 psi,-line pressure @ 30-40 psi | ~ 12 months of operation, well has given back frac. sand- tool still operates @ smaller increase of 450 mcfm vs tool initial of 750 mcfm |
| SR- 1984, Medina Sst 3077' | 5-6 mcf/d open hole periodic swab production | 20-35 mcf/d | 2-4 Bbls/ wk @ 1 run/ day to 1 run/ 2 days | 6+ months of uniform tool operations and stable production |
| CWD St#3 Grimsby/ Whirlpool @ 2120' | 1-2 mcf/d w open hole and periodic swabbing- | 2-6 mcf/d | 1 run each 1.5 to 2 days @ 4 to 8 Barrels/ fluid/ run, down hole pressure @ 400 psi,-line @ 45-60 psi, well dead @ 50 psi- post tool run pressure @ 215 psi and on increase | Test curtailed as brine production storage exceeded [40-50 Bbls of brine/ week], production was on increase & post run follow on pressure increased- other wells in group will be tested with les excessive brine production |

- 5.12 Qualitative evaluation and limited comparison of conventional brine/ fluid removal techniques commonly deployed in similar wells to the chosen test wells is given below as a compilation of information in an anecdotal format developed from interviews with well operators.

Existing methods for brine removal in Stripper wells more commonly include:

[Note: These methods are common to many Geologic Fm. and wells]

- Periodic swabbing with a “work over” rig to remove accumulated brines and temporarily restore gas flow, requiring a normal two man complement, appropriate swabbing tools, equipment and investment of several hours total time for a 3000 to 4000’ well. Effects of the intermittent fluid removal are noted to last a few days to weeks before yield again declines due to water off of gas. Cost of service ~ \$300- \$700/ event [assumes less than 3-4 hours per swab event]. Capital cost of equipment \$30,000- \$50,000.
- Installation of casing swabs that operate by dropping of the mechanical operated casing swab to a preset stand. When the tool strikes the stand it mechanically closes a valve regardless of the height of column of fluid atop the tool and regardless of the pressure below the tool to lift fluid column and tool weight to the surface. These types of tools normally require manual release and often man assisted recovery. Normal capital cost \$5,000- \$7,000 for tool assembly & man assisted operation. Automation [well head] additions \$1,500- \$4,500. Limitations are the tool must go to the stand to be activated and then be capable of lifting the entire column of fluid atop the tool to the surface. This tool is not able to remove fluid accumulation in increments [all or none].
- Installation of smaller diameter tubing in 4 to 6 inch wells [commonly 1.5 to 2.5” internal diameter tubing] targeted to allow older production gas wells with declining volume and reducing pressure to lift accumulating fluid from the well to the surface via combined capillary action/ velocity increase in the smaller tubing. This technical approach is often employed with the periodic shut in of the well to increase down hole pressure to a level sufficiently high that upon reopening of the well will purge the tubing of the brine/ fluid column. This method also often employs the use of surfactants “soap sticks” to disperse the brine into a foam and “lighten” the fluid column for purging to the surface, the process unit and the brine tank. Capital cost for steel tubing for a typical 3000’ well are \$6000- \$9000 plus installation @ \$1500 and periodic shut in and opening by man. Limitations are that a critical pressure must be overcome and a critical velocity of gas and fluid must be maintained to purge the well of its fluid. Post each purge the well flows for some finite period at the end of which the well is shut in to build pressure and repeat the process resulting in intermittent gas production.
- Tubing plungers/ rabbits are another technology deployed to produce gas from these types of stripper wells via the periodic purging of fluids from the tubing column. The rabbits are in general a smaller version of the mechanical swab tools with greater associated mechanical challenges [need to maintain elevated pressure differential of > 80 psi and elevated fluid/ tool movement velocity to avert stalling and fall back of tool and fluid as well as man-assisted operation and or well

head controls. Tubing cost for a 3000' well are as noted above \$6000- \$9000, rabbits systems can vary from ~ \$1000 to \$4000 with well controllers.

- Pump Jack [Beam Pump] rods, down hole pump and tubing are the historic time honored method for lifting fluid from wells. Capital cost for a 3000' hole are on average \$15,000 for Pump Jack, tubing, down hole pump and rods. External power is required with annual O and M cost estimated at \$2500- \$5000/ year for such a well

All these above technology assisted improvements for fluid removal have a common need for manpower assistance and or some add on well external pressure or electronic activated semi-automated controller. Dropping and retrieval of tools [casing swabs and rabbits] involve the need for periodic service [release and retrieval] by a well tender or well head controller, down time on the well production and or some external assistance such as mechanical or electric timers for dropping of tools. Periodic swabbing by a work over rig is the most labor intensive and least cost effective of all methods. Tubing and soaping to lift fluids similarly results in well production down time during periods of well shut in to build pressure to purge the well and also require appropriate manpower. Pumps jacks have elevated cost and on going significant O and M cost associated with energy consumption and operating components wear.

Interviews with well tenders and operators alike when questioned, what dictates the frequency of servicing a well where one or the other of the above technology is deployed? Most record a common refrain, "When there is sufficient time to get to it [the well]". Most well tenders interviewed were found to be servicing 50- 80 stripper wells, some more. As such production is highly dependent upon the frequency of service by the operator and punctuated by periods of non-production and spike production.

One such interview on frequency of service and method of operation with a well tender of more than 30 years experience focused on his experience with the most comparable [albeit not operationally comparable to the design and operational results of the G.O.A.L. PetroPump] technologies of casing swabs/ mechanical swabs/ 'dumb swabs. Questions posed to operator were simply when and how do you decide to deploy or "Drop" a mechanical swab tool and what do you do if problems arise with it cycling/ returning to the surface with brine:

- ◆ The candid response was, as a conscientious operator he tries to inspect the well every two to three days and make a qualitative determination of well production and wellhead pressure. At such time as he determines from his inspection and interpretation of the process unit analogue volume/ flow production chart, pressure reading at the process unit and possibly a well head pressure reading that production and pressure are not acceptable [i.e. gas flow volume down and pressure down based upon qualitative assessment], the mechanical swab tool is physically released from the catcher to the well.
- ◆ The well is then next inspected one or two days in the future. The inferred reasoning on this lapse in time frame is that the tender has previous empirical experience indicating, that is the approximate time it takes for the tool to make a 'run' [i.e. return to the surface with fluid] in that the mechanical tool must drop completely through the accumulated fluid column to the well stand to set the tool/ close the mechanical valve before it can initiate a run. This presupposes that the fluid column is sufficiently short and the below mechanical tool pressure

sufficiently great to lift both mechanical tool and column of fluid to the surface for processing [often not the case].

- ◆ If/ when the mechanical swab tool does not return to the surface, the base interpretation and common empirical experience indicates that this is due to the fact that the pressure behind the tool is insufficient to lift tool and fluid column atop the tool.
- ◆ Follow up actions to retrieve a stalled mechanical swab tool can vary and usually evolve from the simplest response of “shutting in” the well to build down hole pressure for 1 to 2 day [s] with subsequent release of the pressure rapidly directly to the brine tank. More involved and evolved actions can include the addition of a surfactant, shut in of well to build pressure and subsequent purge to brine tank to the more complex action of tool retrieval techniques using other mechanical equipment and tools.
- ◆ This non regular purging of the well of the fluids and often long periods of low to no gas flow resultant from stalled mechanical swab tools is referenced to periodically lead to down stream effects such as winter icing of the process unit further reducing gas output from the well.
- ◆ The well tenders’ summary of operation of wells with mechanical casing swabs is that it tends to produce gas from the well in an uneven and punctuated manner. There are further frequent periods of well down time leading to less overall gas production than the well is capable of were the brine uniformly and regularly removed.

5.13 Significant Accomplishments under this contract Subcontract No.2052-BEDC-DOE-1025 A-3

- Reduced tool size to 32” length, weight to 42# and total parts to 14, a collective 50% miniaturization from ancestral tools
- Developed metallurgical compatible components with down hole fluids for key “Actuator” automated on tool control component
- Achieved ~ 98% compliance of machined parts and components with design spec and lab to field operational performance
- Designed, developed molds, constructed and successfully deployed a new 4” OD “Cross Banded” cup with improved seal fit for passing in well collars with reduced pressure/ fluid loss and increased longevity of cups. Note: Some Brandywine tools have made hundreds of tool cycles on the same set of cups, a key seal/ lift/ wear [former wear] component.
- Designed, developed and successfully deployed and operated a 4/3 convertible tool for use with 3” and 4” ID tubing around a standardized field tested Actuator automatic control with new BEDCO “Cross Banded” cups.
- Designed, developed and constructed molds and cups for 3” ID and 5” ID tubing for broader tool application in stripper wells
- Successfully deployed and retrieved the tool in more than 8 wells and found the tool in post application use [current model] to show little tool and or cup wear and be with in 0.5%-3% tolerance of original specification and settings after use.
- Developed concept plans and designs for re-fitting large diameter and or open hole completed wells with non-metallic tubing and 3”, 4” and or 5” versions of the GOAL tool affording the opportunity for greater production at lower down hole pressures and re-completing wells with non metallic tubing. Challenges for actual field completion include metal to non metal connectors at well head

- and down hole anchor, as well as “New Flex Wall” cup capable of 0.5” OD diameter change w/ out loss of sealing properties
- In an on going march toward commercialization of the tool system Brandywine has developed a Web site with on Web Site tool animation/ operation sequence, on line well data quantification sheet for potential customer response/ tool application, trade show tools, demonstration elements and response offering in field testing.

Project Schedule

| Task Performed | Year- Quarters |
|----------------------------------|----------------------------------|
| | [2001][2002][2003][2004] |
| Design tool/ modify design | >>>>>>xxxxxC |
| Construct Proto/ Beta type tools | >>>>>>xxxxxxxxxC |
| Select Candidate Well [test] | >>>>xxxxxxxxxxxxxxxxxC |
| Bench Test Tool | >>>>>>>>>>>xxxxxxxxxC |
| Test Well Production | >>>>>> xxxxxxxxxxxxxxxxxxxxC |
| Evaluation of Performance | >>>>>>>xxxxxxxxxxxxxxxxxC |
| Evaluate/ Estimate/ Recommend | >>>>>xxxxxxxxxxxxxxxxxC |

Key: >>>> -Original scheduled time frame
 xxxx -Revised time frame to complete
 C -Completed task

6.0 EVALUATE ECONOMICS

6.1 Potential economic payback from the use of the GOAL PetroPump is estimated below from results of current beta tool production increases in the LRI # 52 well, LRI # 29, SR 2023 and SR 1984. This data used in the base calculations was derived from operations in 2001 through 2004. As noted above in an earlier section, redeployment of the predecessor [54” tool] tool in well # 52 and LRI # 29 had improved production in the month of September and October 2002 to an average of 17.5 mcf/d [note this is during a period of lowest pre meter gas consumption by the local Agra business tapped into this well. Recent average production for this well [normal to elevated Agra business consumption] with the newest Beta tool [a 4/3 convertible tool] is 13 to 15 mcf/d. This well was chosen as it represented the first well chosen for tool deployment, the longest history of under GOAL Tool production and among the lowest yielding wells pre GOAL Tool deployment.

6.2 Estimates of Payback from Production

Assumptions:

- “Tool” Cost and Well Modifications @ \$13,500.00
- LRI # 52 Monthly Average Production with Tubing @ 98 mcf
- LRI # 52 Monthly Average Production with ‘ Std. casing plunger’ @ 252 mcf
- **Value of gas @ \$5.00 mcf**

Table 6-2 LRI # 52 Well Performance- Pay Out

| Ave. Prod. using GOAL Pump | Ave. Prod. using tubing in 1995 | Average Prod. Using 'casing plunger' | Payback @ \$5 mcf vs tubing production | Payback @ \$5 mcf vs 'casing plunger production |
|----------------------------|---------------------------------|--------------------------------------|--|---|
| 381 mcf month | 98 mcf month | 252 mcf month | ~9.5 months | ~21 months |

Table 6.3 Pay Out on Other Example Wells Tested Using Improved Production from GOAL Tool only. [Base production from prior operation subtracted as with LRI-52]]

| Well and Prod. w/ GOAL Pump | Pre- GOAL Pump Production- method | Pay Out @ \$5/ mcf w/ tool Cost @ \$13,500 | Comments |
|-----------------------------|---|--|---|
| LRI-29/ 360 mcf-month | 210 mcf-month w/ std. casing swap | 18 months | The GOAL pump has operated in this well for more than 1 year w/ out change of seal cups |
| LRI-332/ 540 mcf-month | 180 mcf month with standard casing swab | ~ 7.5 Months | Well gave up frac sand/ tool recovered w/ out external assistance |
| SR 2023/ 475 mcf-month | 150 mcf month with periodic swabbing w/ rig | ~ 8.5 Months | 1]This well has produced as much as 750/ month w/ tool-2]frac sand currently slows tool runs & production to ~ 450 mcf/ month |
| SR 1984/ 750 mcf-month | 180 mcf-month w/ periodic swabbing w/ rig | ~ 5 months | Well has regularly produced up to 30-35 mcf/d when down stream compression stable |

It must be noted that the pre test yields of most of the wells tested were very small [~3+ to 7 mcf/day of gas via tubing, standard casing swab or open hole/ swab operation at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. Half of these wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater initial production and potential [i.e. the average stripper well] which have need for regular automatic brine [fluids] removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately \$13,500 complete with wellhead modifications for installation is not inexpensive for stripper wells. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner may reduce cost. Improvements in Natural gas and crude oil price increases can shorten payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulate frequency and volume of fluid removal from wells differs greatly from casing plungers, tubing plungers, siphon

tubes, velocity strings and pump jacks producing superior results in these test and has its own unique market niche. Reduction in O and M cost further benefit the use of the GOAL Pump with its limited number of moving parts and increased life seal cups [> 1 year in field trials].

6.3 Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of \$15,000 - \$40,000. Operating cost for pump jacks range from \$2000 to \$10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.
- Tubing string production could have \$6,000 to \$15,000 capital cost dependant on tubing diameter and operating cost ranging in the \$1500- \$3000/ year for manpower & surfactants.
- Casing plungers' capital cost with the necessary well head modifications to receive the unit are in the range of \$5000 to \$7000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at \$1000 to \$5000. Operating cost would include manpower at a minimum of \$500 to \$1000/ year to \$2000- \$3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are \$750-\$1000.
- Tubing plungers [Rabbits] base requirements include the installation of a tubing string at \$6,000 to \$15,000 as noted above plus the capital cost of a Tubing plunger at \$1000 without any automation to \$4000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at \$1000 to \$3000.

Further with respect to casing plungers [must strike down hole stand to set tool and lift total fluid column] and tubing plungers [minimum ascent velocity required for tubing plungers], they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole smart Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the immediate test area of New York State. It was determined that approximately 3,523 gas wells and approximately 529 active oil wells exist in Chatauqua County, New York where 5 tools were tested. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chatauqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.

Assuming only an 8-mcf/d increase per well [in range of test increases] at \$5/ mcf could yield $> \$21,000,000$ in gas value and a pay back on 1500 tools at \$13,500/ tool in a one year time period.

Were one to use the average increase from the SR wells # 2023 and 1984 where the increase was ~ 15 mcf/d for each of the wells pay out could be achieved in ~ 5 to 6 months.

- 6.4 Over the recent years several organizations have begun to evaluate the number of stripper gas and oil wells in the United States which exist and are troubled by water production. BEDCO's review of the number of wells for which the technology being developed may be applicable is derived from several sources. Those specifically referenced here in are:
- National Survey – Marginal Oil and Gas Report by IOGCC [Annual]
 - Ohio and West Virginia Survey – University of Kentucky by E. Choong
 - New York – IOGANY Marginal Well Study sponsored by NYSERDA 2000
- 6.5 Results of review of those above referenced documents by Brandywine indicate nominally $\frac{1}{4}$ to $\frac{1}{3}$ of all stripper wells as potential candidates for the use of the standard 4.0" OD tool. Current total numbers of stripper wells in the lower 48 states of the US is in excess of 630,000 with an approximate $\frac{1}{3}$ of them gas wells to $\frac{2}{3}$ oil stripper wells. With the increase in natural gas demand in the past decade there is a growing number and percentage increase of gas stripper wells vs. oil stripper wells in that mix.
- 6.6 The applicability of the GOAL tool to a larger number of those above referenced stripper wells may be accommodated as technology improves to re-fit wells with failed or irregular casing, current open hole and telescoped casing completions with spoolable non-metallic tubing and a down sized- variable diameter "Flex Cup" version of the GOAL Pump 4/3 @ 3.0" OD configuration.
- 6.6 As specific example of some of the wells tested during this contract include those at the RMOTC facility north of Casper Wyoming. These wells are 5.5" OD with fluid levels currently at or below the perforations to below casing. These wells could be sleeved with 4.5" OD spooled non-metallic tubing [or 3.5" OD and the in planning GOAL 4/3 tool which is convertible to a 3.0" OD tool] affording opportunity for a GOAL tool to operate at several hundred feet greater depth [potentially in the spacious rat hole]. At those depth in those wells sufficient fluid would be available atop the tool to set the internal actuator closing the valve; further the spoolable synthetic tubing would afford less friction loss and greater lift potential resulting in more total fluid and gas produced from the reservoir and lower ultimate abandonment pressure and left behind reserves.
- 6.7 A similar opportunity affords itself for the Chatham wells [Cdn] C- 14 and C-35 which have a telescoped variable diameter casing which caused cup/ tool binding and erratic tool runs and shut downs.
- 6.8 In Brandywines' review of potential stripper wells for tool application, tens of thousands each of; open hole completions, telescoped completions and wells where fluid level was at or below perfs and down hole pressure/ pressure differential was marginal for current tool configuration and standard casing configuration could be self pumped with the now being developed 4/3 GOAL Pump and a re-fitted length of non- metallic spoolable tubing. Additional field work is needed there on to gain in field oil and gas industry acceptance and field prove out bench results.
- 6.9 Further to the applicability of the GOAL Pump to industry needs, a GRI study by Spears indicates > 200,000 stripper wells in North America producing < 25 barrels of

fluid/ day. This 25 barrel/ day quantity is within the current empirically determined lift capacity of the standard GOAL PetroPump.

CONCLUSION

The need for and applicability of a Gas Operated Automated Lift PetroPump [A Smart Swab Tool] for removal of fluids from a significant percentage of stripper wells we believe has been proven by this field applied research for the oil and gas wells of America and the world. Key elements of the GOAL tool leading to increased production and automatic pumping are its unique on tool variable lift actuator [it does not have to go to the base of the well to be set], resilient long life tool to casing seal cup and abilities to work in varying geologic environments of pressure, depth, fluid production, in well chemistry and operating conditions. Current target wells for which the tool is readily deployable and serviceable in 4" ID wells; with but minor structural changes to the well head and process units to be economically viable. Increased yields of 1.5X to 4.0X + have been achieved in this field test on wells whose base yield was 7 mcf/d or less. Empirical data from the test has shown that in the wells tested the greater the base yield [pre GOAL tool] the greater the post tool gain in production with achievable payback on the tool at a current price of \$13,500 achievable in 5 or less to ~ 12 months for those low yield wells tested.

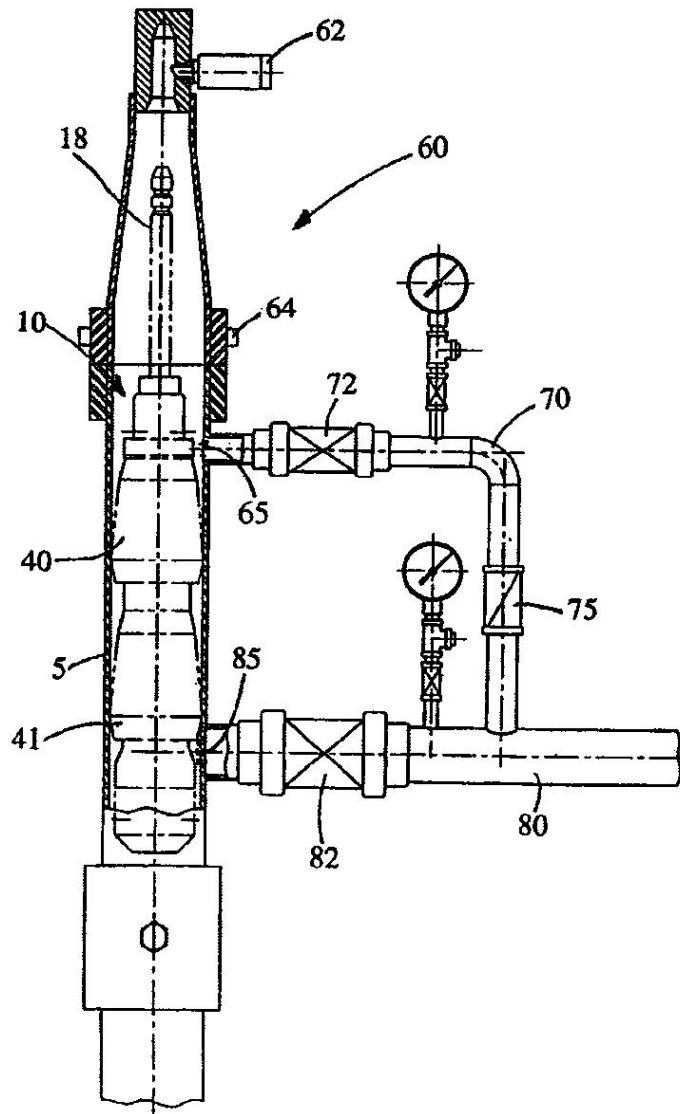
Future needs of such a Gas Operated Automated [lift] Tool will target wells with 3.0" diameter tubing, telescoped variable diameter casing and or open hole/ large diameter completion wells or open hole completions that could be retrofit with isolation packers and continuous smaller diameter tubing than the nominal open hole diameter of 6.25".

Bench and test stand testing of varying automated valve closure assemblies and engineering calculations and field test indicate potential operating ranges for the prototype and beta type tool at 50 to 600+ [psi] and potential fluid lift of 0.1 to 9+ bbl's per tool cycle. Field trials of the prototype and beta tool have confirmed the ability to operate through out these bench-tested values. Note: Field empirical data does show at least [1] one 40+ barrels lift without tool and or cup damage.

Automated computerized well head data loggers show they can record varying location pressures at the well head and process unit, as well as continuous volume of production. These units have evolved to a point to be applicable for in field continuous recording of operating conditions of the GOAL tool. This data can serve to act as basis of tool adjustment for optimum performance and to target tool components for upgrade and improvement. These type of instruments with large variable input pressures and rates of flow can also more accurately capture total gas produced and diurnal and long term trends in gas and fluid production. Note: Use of one such unit on a tested well evidenced some 20- 40 mcfm as not being captured and/ accounted for in an industry standard analogue meter and pie chart following automatic tool runs. At gas prices of \$5/ mcf or greater this could represent ~\$1200-\$2500 annual revenues which could foster even quicker payback on the GOAL tool when and where employed.

On a national basis tens of thousands to perhaps 100,000 or more of stripper wells appear applicable for use of the technology to improve production. Production increases even if equal to low range of the GOAL tool results [7 mcf/d] on 10,000 wells can amount to >120 millions of dollars worth of additional recovered energy resources annually at modest well head re-configuration and G.O.A.L. PetroPump cost which could be recovered with in < 1 years based upon recent field tool test results. Tool modifications and improvements can make the tool more durable and better functioning to further increase performance and shorten pay back on capital tool investment and more widely applicable to more wells.

FIG. 1



BEDCO G.O.A.L. PetroPump Schematically Shown in Well Head Lubricator

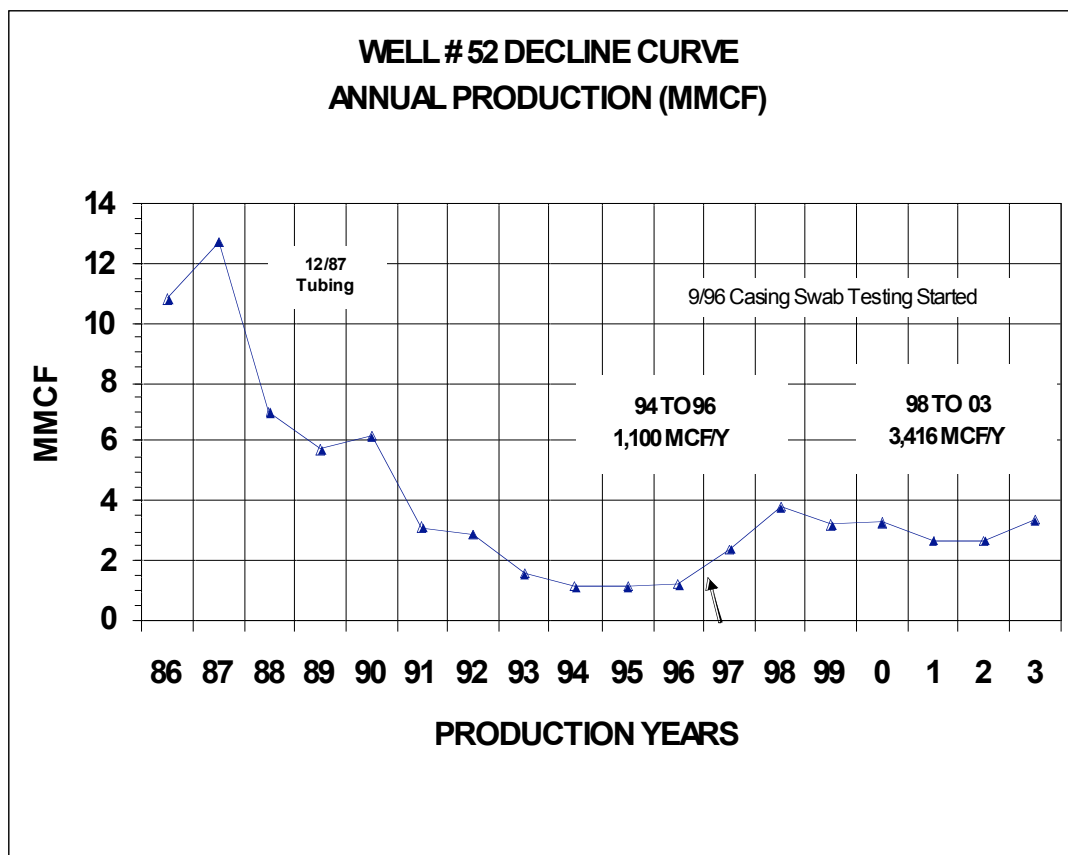


Figure 2: Annual Gas Production From LRI Well #52, Before and After GOAL Tool Installation

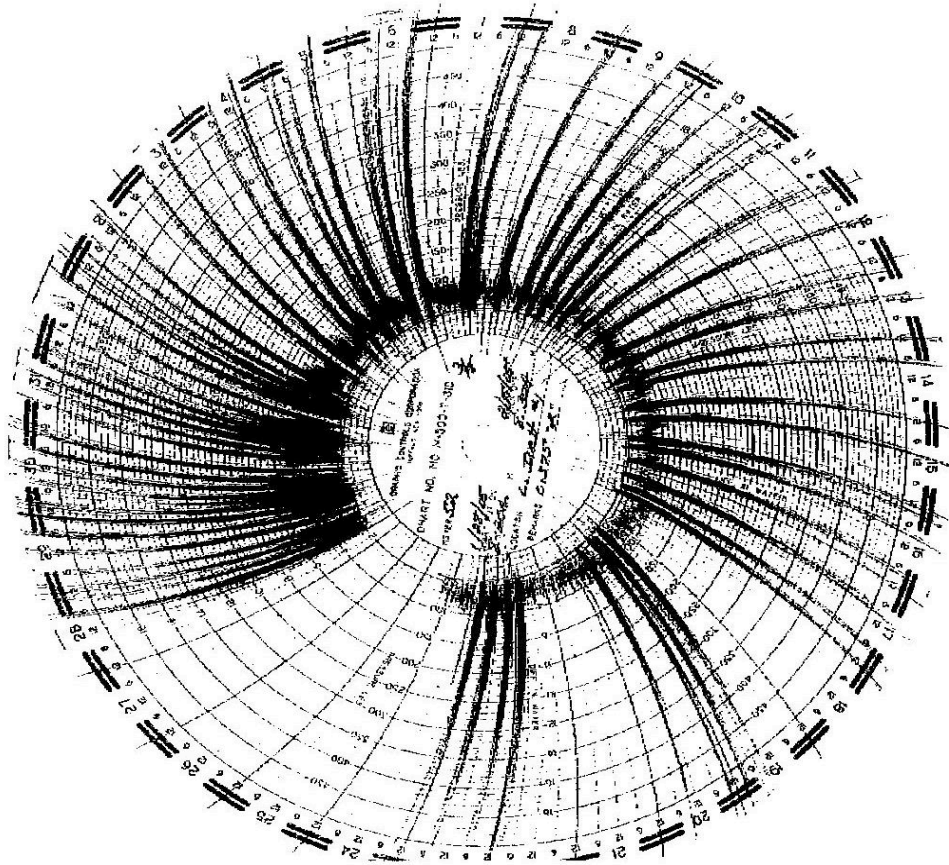


Figure # 3

Typical Well Production Chart Showing GOAL Tool Runs on LRI # 52

Notes:

- 1] Analogue Pie Chart for well LRI, Feb 2005
- 2] Tool runs = Spikes on chart @ ~ 50+ trips for the month
- 3] Three + [3+] days well down due to process unit problems
- 4] GOAL Tool deployed newest version 4/3 Tool in 4" mode w/X-banded cups

Appendix 1

Table 1 - 1 Tested Well # 52

| | | |
|--------------------------|-----------------------------|------------------------------|
| Test Period | 1996/1997 | 2001/2002 |
| Completion date | 11-1-83 | 11-1-83 |
| Formation | Medina [Grimsby/ Whirlpool] | Medina [Grimsby/ Whirlpool] |
| Geology | Sandstone [tight] | Sandstone [tight] |
| Total Depth | 3,343 feet | 3,343 feet |
| Perforations | 3,127 – 3,229 feet | 3,127 – 3,229 feet |
| Casing size | 4.5" | 4.5" |
| Production prior to test | 3 mcf/d via tubing | 8mcf/d w/ casing plngr. tool |
| Well head pressure | 320 c/ 60 t psig | 180 psig |
| Line pressure [sales] | 60 psig | 55 psig |
| Bottom Hole Temperature | 97 deg. F | ----- |

Table 1 – 2 Candidate Test Well # 29

| | |
|--------------------------|--|
| Test Period | 2002 |
| Completion Date | 1982 |
| Formation | Medina [Grimsby/ Whirlpool] |
| Geology | Sandstone [tight] |
| Total Depth | 2390 |
| Perforations | 2299 – 2370 |
| Casing size | 4.5" |
| Production prior to test | ~9 mcf/d w/ std. casing plunger tool [4-5 mcf/d w/ natural flow] |
| Well head pressure | 150 psi |
| Line pressure [sales] | Variable 25 to 45 psi |
| Bottom Hole temperature | ? |

Appendix 2

Attachment C in Original Proposal with Noted Modifications to Reflect Actual Expenditures by BEDCO

| | Requested from SWC | Proposed Cost Share by BEDCO | Expended Cost Share by BEDCO |
|---|--------------------|------------------------------|------------------------------|
| Salaries and Wages | \$112,638 | \$224,675 | \$464,064 |
| Fringe Benefits | -- | -- | -- |
| Materials and Supplies | \$7,400-- | -- | -- |
| Equipment | \$17,100 | -- | -- |
| Travel | \$30,560-- | \$2,170-- | \$2,400-- |
| Publication/ Information Dissemination | -- | \$5,950-- | \$5,950-- |
| Other direct Cost [Misc.] | -- | \$3,250-- | \$4,010-- |
| Prototype tools/ spares and modifications | \$226,815- | -- | -- |
| | | -- | -- |
| Facilities and Administration | \$3,750-- | \$17,280-- | \$17,280-- |
| Totals | \$398,263- | \$253,325— [39%] | \$492,704— [55%] |

Note: Total combined expenditures by SWC and BEDCO on the project are \$890,967.00

| | |
|-------------------------|------------------|
| Total Request from SWC | \$398,263 |
| Total Invoice by BEDCO | <u>\$389,792</u> |
| Balance Returned to SWC | \$ 8,497 |